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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO IMPLEMENT POWER COST ADJUSTMENT (PCA) RATES FOR ELECTRIC SERVICE FROM JUNE 1, 2014 THROUGH MAY 31, 2015, AND TO UPDATE BASE RATES IN COMPLIANCE WITH ORDER NO. 33000.

CASE NO. IPC-E-14-05

COMMENTS OF THE COMMISSION STAFF

The Staff of the Idaho Public Utilities Commission comments as follows on Idaho Power Company's proposed rate adjustments.

SUMMARY OF APPLICATION

On April 15, 2014, Idaho Power Company ("Idaho Power," or the "Company") filed its annual Power Cost Adjustment ("PCA") Application. The Application proposes to implement a base rate increase as required by Commission Order No. 33000. This change also involves a change to Schedule 89 (Unit Avoided Energy Cost of Cogeneration and Small Power Production), a PCA rate decrease with revenue sharing similar to last year's application, and a rate mitigation measure that would apply unused demand-side management ("DSM") Rider revenues to reduce the proposed increase. According to the Company's Application Idaho customers will collectively pay about $11.1 million (or 1.04%) more for electricity in the upcoming year than they do now. Table 1 shows a breakdown of the Company's request.

Table 1: Idaho Power Proposed Revenue Changes for Idaho Customers

Description	Current ($)	Proposed ($)	Difference ($)
Base Revenue Change	898,955,741	998,206,633	99,250,892
Associated DSM Rider Change	0	(3,970,276)	(3,970,276)
PCA without Revenue Sharing	166,855,392	99,047,509	(67,807,883)
Revenue Sharing	(7,276,203)	(7,602,043)	(325,840)
Mitigation - DSM Rider Revenue	0	(16,029,724)	(16,029,724)
Difference			11,117,169
Total Billed Revenue	1,067,597,568	1,078,714,736	11,117,168
Increase in Billed Revenue			1.04%

As can be seen in the table, all proposed changes are decreases except the base rate change. The proposed base rate increase and PCA decrease (including the Company's revenue sharing and mitigation proposals) are further described below. The Company asks that its proposed rate changes be effective June 1, 2014.

A. Proposed Base Rate Increase

Commission Order No. 33000 in Case No. IPC-E-13-20 allows Idaho Power Company to add $99.3 million of normal Net Power Supply Expense ("NPSE") to base rates. The order also identifies about $4.0 million in increased DSM Rider revenues associated with the base rate increase. The DSM Rider recovers 4% of base revenues. The order further requires Idaho Power to spread both amounts in the way the PCA spreads cost or revenue amounts, on an equal ¢/kWh basis. In addition, the costs are to be assigned to the energy rate components of all rate schedules. The order specifies that the rate change would be effective June 1, 2014 along with the Company's PCA rates.

Besides increasing base rates, the base NPSE change noted above also requires the Company to change its rates in Schedule 89, Unit Avoided Energy Cost of Cogeneration and Small Power Production. *See* Order No. 32758. Schedule 89 establishes the rate that Idaho Power pays the owners of some Qualifying Facilities who sell both energy and capacity to Idaho

Power. The rate is based on variable costs of generating power at the Valmy power plant. The current rate is 3.462 ¢/kWh and the proposed rate is 4.133 ¢/kWh.

B. Proposed PCA Decrease

This year the Schedule 55 PCA rate for each class combines the three traditional PCA components (forecast, "true-up," and reconciliation) with two additional components (revenue sharing and rate mitigation). These five components are discussed below.

1. <u>Traditional PCA Components</u>

The traditional annual PCA mechanism has three components: a) a "forecast" or projection that estimates the difference between power supply costs embedded in base rates and the coming year's power supply costs; b) a "true-up" that captures the difference between actual and base power supply costs and credits the revenue from the previous year's forecast rate; and c) a reconciliation of the previous year's true-up that captures any under-recovered or under-refunded true-up amount. This is also called the true-up of the true-up. Each component is described in more detail below.

a. *Forecast.* Forecasted power supply costs for the coming year are based on inputs to the Company's March 27, 2014 Operating Plan. According to the Company, the Idaho ratepayer's share of the difference between forecasted and base power supply cost is about $21.7 million. The power supply cost difference is converted to a cents-per-kilowatt hour (¢/kWh) rate by dividing the power costs by projected energy sales. Idaho Power calculates this rate to be 0.1609 ¢/kWh.
b. *True-Up.* The true-up amount is the difference between forecast and base power supply costs and revenues from the forecast rate that accrued during the previous year. The previous year's PCA amount is not precisely recovered because the forecast of expected costs is never 100% accurate. The true-up amount is also converted to a ¢/kWh rate by dividing by projected energy sales. Idaho Power calculates the Idaho ratepayer's share of the true-up amount to be $58.1 million, which is expected to be recovered by applying a true-up rate of 0.4284 ¢/kWh.
c. *Reconciliation of the True-Up.* The reconciliation of the true-up tracks the recovery of the previous year's true-up amounts. It nets the actual revenue collected from the true-up rates and revenue sharing rates against the amounts set for recovery. Any difference is

carried into the following year's true-up reconciliation along with the true-up difference. Idaho Power calculates the Idaho ratepayer's share of the reconciliation of the true-up amount and rate to be $19.1 million and 0.1412 ¢/kWh, respectively.

These three traditional PCA rate components combine for a 2014/2015 PCA rate surcharge of 0.7305 ¢/kWh (0.1609 + 0.4284 + 0.1412). The implementation of this rate is expected to recover traditional PCA costs in one year. The proposed rate is 0.5001 ¢/kWh less than current PCA rates.

2. <u>Additional PCA Components</u>

Besides the three traditional components discussed above, this year's PCA includes the revenue sharing and mitigation components discussed below.

a. Revenue Sharing

The Company applies a revenue sharing component to this year's PCA. The Company calculates $24.1 million of revenue to be shared with customers. The offset to the PCA is $7.6 million and the remaining $16.5 million is to be applied to the pension balancing account.

b. Mitigation Proposal

The Company also applies a mitigation component to this year's PCA. In summary, Idaho Power proposes to offset the overall June 1, 2014 increase by crediting an additional $16.0 million of DSM Rider revenues to this year's PCA. The $16.0 million amount would come from unused DSM Rider revenues. The Company proposes to spread this amount to the Company's rate schedules on a uniform percent of base revenue basis, and to assign it to the energy rates in each schedule. These class specific energy credits result in a different combined PCA/Revenue Sharing/mitigation energy rate for each rate schedule.

C. Company's Rate Calculation

Company Exhibit No. 6 shows how the Company developed its proposed Schedule 55 rates. Schedule 55 rates include all of the rate changes proposed in this filing except for the base rate change and the Schedule 89 rate change. Column I shows the Schedule 55 energy rates proposed by the Company.

STAFF AUDIT AND ANALYSIS

Staff's analysis of the Company's proposed base rates and PCA rates is summarized below.

A. Analysis of Base Rates

Staff checked the Company's calculations of the proposed base rate, 0.7320 ¢/kWh, and believes the Company's proposed changes are consistent with Commission Order No. 33000. This rate change would require changes to almost all of the Company's tariff schedules.

Staff has also reviewed the proposed rate and rate calculations for Schedule 89 (Unit Avoided Energy Cost of Cogeneration and Small Power Production) and recommends Commission approval.

B. Analysis of PCA Rates

Staff analyzed the traditional PCA components (forecast, true-up, and reconciliation) and additional components applied in this case (revenue sharing and mitigation). Staff's analysis is as follows.

1. <u>Traditional PCA Components</u>

a. Forecast

The Company's forecast is based on its March 27, 2014 Operating Plan. The Operating Plan reflects the most current information available to the Company when its filing is prepared. The forecast considers many factors, including but not limited to: load, water conditions, gas hedges, market purchases, transmission availability and the cost of contracts under the Public Utility Regulatory Policy Act of 1978 (PURPA). Throughout the year, the Risk Management Committee ("RMC"), which consists of key Idaho Power employees, reviews and updates the Company's risk management strategy. An account-by-account breakdown of the Company's power supply expense forecast is shown on Attachment A to these comments. The chart shows expenses included in Base Rates, Forecasted Expenses and the Difference. Account 555 – PURPA Purchase Expense, is shown separately from other Account 555 Non-PURPA Expenses because differences in PURPA Contract Expenses are not shared between the Company and its customers. The entire difference in PURPA Qualifying Facility (QF) contracts is passed on to customers.[1]

Attachment B shows Staff's calculation of the PCA rate components. Lines 1 through 18 show the calculation of the forecast rate. The forecast rate is the sum of three rate elements.

The first element is composed of all PCA amounts subject to 95/5 sharing. Lines 2 through 8 show this calculation. Line 8 shows the first component of the forecast rate to be 0.1807 ¢/kWh. This rate element captures the effects of expected water conditions, thermal plant fuel costs and expected market prices which affect power purchases and sales, etc. Although precipitation amounts are near normal, expected runoff into the Hells Canyon Complex are below normal because upstream reservoirs are expected to store more than normal amounts to fill last year's above-normal draw downs.

The second element of the forecast rate component is shown in lines 10 through 12. The second element includes all amounts, except Demand Response Incentive amounts, which are passed through to customers without sharing. These amounts are almost entirely PURPA QF contract costs. This second rate element is 0.0020 ¢/kWh as shown on line 12. This very small change from base reflects the fact that this filing includes a current updated base NPSE discussed earlier in these comments.

The third element of the forecast rate component allows Idaho Power to capture the difference between base and actual Demand Response Incentive Payments in the PCA. *See* Order No. 32426. The calculation of Demand Response Incentive rates is shown on lines 14 through 16. The difference between these Demand Response payments and base amounts is shown on line 16 to be minus 0.0218 ¢/kWh. The amount is negative because the forecasted amount is less than the amount included in base rates.

Staff verified that the Company appropriately used the Commission-approved Demand Response settlement[2] to estimate the total expenses to be included in the PCA. The Company's forecast for Demand Response incentive payments is higher in 2014-2015 than in 2013-2014, primarily due to the reinstatement of the programs for the 2014 season. The Company's forecast consists of estimated fixed payments for enrolled participants as of April 7. Staff agrees with the

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[1] A QF is a generating facility that qualifies for QF status under PURPA and 18 CFR Part 292 and has obtained certification of its QF status.
[2] See Case No. IPC-E-13-14.

Company's approach for forecasting Demand Response payments for 2014, and notes that as a result of the settlement, the forecasted expenses remain below the base level included in rates.

The above three elements combine to produce the PCA forecast rate component of 0.1609 ¢/kWh shown on line 18. The forecast rate component is not large this year like it was last year mainly because base NPSE has been updated to current normalized levels. Staff points out that any over or under-collected amounts due to forecast error are trued-up in the following year's PCA.

b. True-up

Staff has concerns about the Company's true-up calculations. As a result, Staff proposes a change to the balancing account going forward but no change to the true-up rates to be put in place on June 1, 2014. Staff's concerns are discussed in detail at the end of this section. Before that, Staff discusses the true-up calculations and the way they have been done in recent cases.

i. True-up Calculations and Recent History

The Company's filing nets the PCA true-up difference against the amount collected from the application of the previous year's forecast rate. This difference, with interest, is the PCA true-up deferral balance. This deferral balance is divided by expected jurisdictional energy sales to produce the true-up rate component of the PCA.

Page 1, lines 4 through 90 of Company Exhibit No. 5 calculates a true-up deferral amount of $58.1 million. Attachment C contains Staff's verification of the Company's true-up deferral calculations.

To verify revenues and costs associated with Idaho Power's true-up deferrals, Staff audited the actual revenues and expenses that occurred during the PCA year (April 1, 2013 through March 30, 2014). These revenues and costs included water lease expenses, fuel expenses for coal, fuel expenses for natural gas, power sales and purchases, third-party transmission expenses, Renewable Energy Credits (RECs) sales, Emission Allowance sales, and QF expenses. The Risk Management Operating Plans and Risk Management Committee minutes were also reviewed.

In addition, Staff verified that the monthly calculated and actual amounts for the revenue included in the PCA Forecast, as shown on page 1, line 7 of Company Exhibit No. 5 are correct, and that the megawatt hours used for the Actual Firm Load, as shown on page 1, line 10 of Company Exhibit No. 5 are correct.

The large true-up balance, $58.1 million, indicates that the prior year's forecast was inaccurate. The actual hydro generation was lower during the PCA year when compared to what was built into the forecast. This lower hydro generation also contributed to lower surplus energy sales revenue. These two factors are the most significant factors that contributed to the large PCA true-up deferral balance.

The PCA true-up component includes the following items:

- Load Change Adjustment. This year's true-up calculation includes a negative load change adjustment of $643,172. Actual loads during the true-up year were below normal loads in 6 months and above normal in 6 months. Overall, the actual load for the PCA year was above normal by 36,461 MWh. This represents a 0.23% overall increase in load. During the PCA year, the monthly increase in loads was greater than the monthly decrease in loads, producing a negative Load Change Adjustment amount.

  The load change adjustment is the product of the positive or negative load growth and the load change adjustment rate (LCAR) of $17.64/MWh for the months of April 2013 through March 2014. The LCAR is composed of the energy-classified fixed costs of production embedded in base rates. When load grows, the adjustment reduces power supply costs to avoid double counting production costs. When load declines, the adjustment reimburses the Company for a portion of lost fixed production costs.

  The result is that $643,172 (before jurisdictional allocation and PCA sharing) has been subtracted from the deferral balance for recovery from customers in this year's PCA. This LCAR-related decrease is a benefit to customers and is subject to jurisdictional allocation and sharing.

- Water Leases. The Company sometimes leases water from several entities for hydro power production. The increase or decrease in the water lease expense from base rates is included in the PCA for recovery from, or credit to, customers. This year's PCA deferral balance includes actual water lease expenses of $706,411. The amount included in base rates is $1,828,640. The difference of $1,122,229 is included in the deferral balance. This decrease in water lease expenses from base expenses is a benefit to customers and is subject to jurisdictional allocation and sharing.

- Fuel Expense - Coal. Some of Idaho Power's electricity comes from coal plants. Idaho Power owns an interest in three coal plants: Bridger, Valmy and Boardman. The increase or decrease in the coal expense from base rates is included in the PCA for recovery from or credit to customers. For the April 2013 to March 2014 PCA period, the total coal expense for the three plants is $160,995,670. The total coal expense included in base rates is $167,192,743. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $6,197,073. This decrease in coal costs from base costs is a benefit to customers and is subject to jurisdictional allocation and sharing.
- Fuel Expense - Gas. Idaho Power owns and operates gas-fired combustion turbine generating plants at the Evander Andrews Power Complex (3 Danskin units) and Bennett Mountain in Mountain Home, Idaho; and Langley Gulch, near New Plymouth, Idaho. Langley Gulch was included in base rates beginning in July 2012. Staff reviewed the natural gas purchases in conjunction with the Company's Operation Plan. Staff found that the transactions were reasonable and followed the Risk Management Committee recommendations.

  For the April 2013 through March 2014 PCA period, the total variable gas and gas transportation expense for all the gas plants was $59,228,806. The total gas and gas transportation expense included in base rates is $51,934,201. This increase in gas expense from base rates is included in the PCA. This year's PCA deferral balance includes a difference between costs currently included in rates and actual costs of $7,294,605. This increase in natural gas expenses from base expenses is a cost to customers and is subject to jurisdictional allocation and sharing.
- Power Sales and Purchases. Staff reviewed the power purchases and sales in conjunction with the Company's Operating Plan. Staff believes the transactions were reasonable and that they followed the Risk Management Committee recommendations. These transactions were made with an assortment of creditworthy partners on a timely basis, and there were no transactions conducted with an Idaho Power affiliate.
  a. Power Sales. During the PCA year ending March 31, 2014, the Company sold off-system surplus power totaling $66,784,731. The total surplus sales included in base rates is $124,916,153. This decrease in the power sales from base rates is included in the PCA. Actual surplus sales were less than base amounts by

$58,131,422. This decrease in revenues is a cost to customers and is subject to jurisdictional allocation and sharing.

Company witness Tatum explains that forecasted surplus sales deviated from actual surplus sales because surplus sales were impacted primarily by lower hydro generation. *See* Tatum Di, Exhibit No. 2, p. 1 at 3. Tatum also explains that surplus sales were lower due to lower production at Langley Gulch power plant, with the accompanying decrease in natural gas costs. In addition, there were months where surplus sales were lower due to maintenance at Langley Gulch and lower than expected natural gas prices, but that overall the decrease in surplus sales directly correlates to the lower than anticipated hydro generation.

b. Power Purchases. During the PCA year ending March 31, 2014, the Company made $78,523,687 in market power purchases, excluding its PURPA contracts. The amount of power purchases included in base rates is $45,510,094. Actual power purchases were more than base amounts by $33,013,593. This increase in purchases is a cost to customers and is subject to jurisdictional allocation and sharing.

- Third-Party Transmission. In Order No. 30715, the Commission found that third-party transmission costs that are incurred in conjunction with market purchases and off-system sales should be tracked through the PCA like other variable power supply costs. Including transmission expenses in the PCA is a straightforward treatment of power supply costs that fluctuate with power purchases and sales. For the April 2013 through March 2014 PCA period, the actual third-party transmission expense is $5,760,718. The third-party transmission expense included in base rates is $8,262,000. This year's PCA deferral balance includes the difference between actual costs and base costs of $2,501,282. Because the actual costs are less than the amount included in base rates, this amount represents a benefit to customers. This benefit to customers is subject to jurisdictional allocation and sharing.
- Hoku First Block Energy. In Order No. 32426 (Case No. IPC-E-11-08), the Commission determined that the first block energy revenue from Hoku is to be included in base rates like secondary sales revenue. The variation between what is built into base rates and the actual Hoku revenues is tracked in the PCA. The amount of Hoku First Block Energy revenues included in base rates is $23,921,467. The actual amount of Hoku First Block

Energy revenues during the current PCA period is $0. New base rates set in Order No. 33000, Case No. IPC-E-13-20, no longer includes any Hoku revenues. The actual revenues during the PCA year are less than the amount included in base rates by $23,921,467. This decrease in revenues is a cost to customers and is subject to jurisdictional allocation and sharing.

- Emission Allowance Sales. In Order No. 32424, the Commission required that revenues from the sale of emission allowances, plus any applicable interest, be reflected in the PCA and benefit customers by reducing the Company's PCA deferral balance, subject to jurisdictional allocations and sharing. In the current PCA period, emission allowance sales totaling $24,000 are included in the deferral balance. This increase in revenues is a benefit to customers and is subject to jurisdictional allocation and sharing.
- Renewable Energy Credit Sales. In Order No. 30818, the Commission ordered that revenues from the sale of renewable energy credits ("RECs") benefit customers and be subject to jurisdictional allocation and sharing. The amount included in the deferral balance is $1,874,892. This increase in revenues is a benefit to customers and is subject to jurisdictional allocation and sharing.
- Actual PURPA Purchases Including Net Metering and Raft River Expenses. For the April 2013 through March 2014 PCA period, the actual PURPA expense is $133,003,093. The PURPA expense included in base rates is $62,851,454. The difference between actual PURPA expense and base PURPA expense is included in the PCA for recovery from or credit to customers. In this year's PCA deferral balance, the actual PURPA expense exceeded the PURPA expense included in base rates by $70,151,639. This amount is a cost to customers and increases the PCA deferral balance. PURPA contracts are not currently subject to sharing, but they are subject to jurisdictional allocation.
- Demand Response Incentive Payments. In Order No. 32426, Case No. IPC-E-11-08, the Commission required that Demand Response Incentive Payments be included in base rates and that differences between base and actual expenses be tracked through the PCA. Idaho Demand Response Incentive Payments are directly assigned to Idaho and are not subject to sharing. For the PCA period (April 2013 to March 2014), the actual Demand Response Incentive Payments are $4,197,214. The base amount of Incentive Payments included in base rates during the PCA period is $11,252,266. The difference between the

actual amount and the base amount is $7,055,052 and is a reduction to customer PCA costs. The Demand Response Incentive Payments are not currently subject to sharing and are allocated 100% to the Idaho jurisdiction.

Table 2 summarizes the composition of the deferral balance.

Table 2: True-Up Deferral

Description	Deferral Amount
Load Change Adjustment	(643,172)
Water Leases	(1,122,229)
Fuel Expense - Coal	(6,197,073)
Fuel Expense - Gas	7,294,605
Surplus Sales	58,131,422
Non-Firm Purchases	33,013,593
Third Party Transmission Expense	(2,501,282)
Hoku First Block Revenue	23,921,467
Subtotal	111,897,331
Emission Allowance Sales Credits	(24,000)
Renewable Energy Credit (REC) Sales	(1,874,892)
Subtotal	109,998,439
Amount After Jurisdictional Allocation and Sharing	99,273,591
Qualifying Facilities - After Jurisdictional Allocation	66,644,057
Demand Response Incentive Payments	(7,055,052)
Total Expense Items	158,862,596
Revenue from PCA Forecast	101,039,775
Deferral Balance	57,822,821
Interest on the Deferral Balance	266,054
Total Deferral	58,088,875

The Company proposes a 0.4284 ¢/kWh true-up rate. Staff calculates the same rate as the Company, as shown on Staff Attachment B, line 23.

ii. Staff's Concerns about the True-up

The purpose of the PCA is to track the difference between actual power supply expenses and power supply expenses collected through base rates and then true-up to "ensure the amount recovered is no more or less than actual power cost paid by the Company."[3] The recovery of actual NPSE can be mathematically expressed as follows:

$$\begin{array}{c}\text{Actual NPSE}\\ \text{Cost}\end{array} = \overbrace{\begin{array}{c}\text{Recovery of NPSE}\\ \text{through Base Rate Sales}\end{array} + \begin{array}{c}\text{PCA}\\ \text{(Base-to-Actual True-up Deferral)}\end{array}}^{\text{Total Recovery of Actual NPSE}}$$

The problem with the Company's true-up calculation is that it uses load-at-generation in the Load Change Adjustment (LCA) rather than Idaho jurisdictional sales. Taking the difference between actual load-at-generation and load-at-generation used to establish base rates introduces a line loss bias. Line loss is the difference between load-at-generation and load-at-sales. In this case, actual line losses are significantly less than those assumed in the last rate case resulting in underestimated actual sales used to determine NPSE actually collected. *See* Attachment D to these comments

Because of base-to-actual line loss differences and because the Company uses loads at generation, Staff believes that the Company has failed to properly include power supply expense revenue actually collected from customers through base rates and has therefore over estimated the amount of additional expense that needs to be collected through the PCA true-up component. The adjustment for actual NPSE revenue collected from customers includes four parts: 1) Actual non-PURPA NPSE; 2) energy classified fixed production costs; 3) Qualifying Facility Net Power Supply Expense (QF NPSE); and 4) DSM incentive costs. In summary:

1) During this PCA period, actual non-PURPA NPSE was $226.5 million for the Idaho jurisdiction before sharing. The amount of non-PURPA NPSE collected through actual sales for the period totaled about $125.7 million (13.85 million MWh in actual Idaho sales, times

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[3] See Order No. 30828, Case IPC-E-09-11. The Commission States, "We remind customers frustrated by the rate increase that the PCA does not influence Idaho Power's profits. The Company's normal power costs are recovered in its base rates, and the PCA recovers only the actual variable costs the Company pays to supply the power used by its customers. Both the true-up component and the reconciliation of the true-up [true-up of the true-up] are measures in the PCA to ensure the amount recovered is no more or less than the actual power costs paid by the Company."

$9.079/MWh of non-PURPA NPSE in base rates) for an unrecovered balance of $100.8 million. The Company has requested a true-up in this case of $106.6 million (the Company has included a non-PURPA NPSE LCA of -$ 279,540) resulting in a $5.9 million over collection of actual non-PURPA NPSE before sharing and $5.6 million after sharing.

2) Idaho's share of actual energy classified fixed production cost is about $109.1 million. This amount is assumed to be the same amount included in base rates through the authorized LCAR. Total recovery of $114.4 million consists of collection through base rates of $114.7 million (13.85 million MWh in actual Idaho sales times $8.28/MWh of cost embedded in base rates) plus a reduction of about $250,000 through the energy classified fixed production cost portion of the Company's LCA. Total over-collection during the deferral period would be about $5.3 million before sharing and $5.1 million after sharing.

3) Idaho's share of actual QF NPSE during the deferral period was $126.4 million. The amount of QF NPSE collected through actual sales for the period totaled about $62.8 million (13.85 million MWh in actual Idaho sales, times $4.53/MWh of QF NPSE in base rates) for an unrecovered balance of $63.6 million. The Company proposes to collect a true-up of $66.6 million resulting in an over collection of about $3.0 million.[4] No additional sharing is applied to this component.

4) Idaho's share of actual DSM incentive costs during the deferral period was $4.2 million. The amount of DSM incentive costs collected through actual sales for the deferral period totaled about $11.8 million (13.85 million MWh in actual Idaho sales, times $0.85/MWh of DSM incentive costs in base rates) for an over recovery of $7.6 million. The Company proposes to refund $7.1 million resulting in a continued over collection of about $500,000.

See Attachments E and F to these Comments for further detail.

When actual revenue collected from customers during the PCA period in these four NPSE categories are compared to actual NPSE incurred during the PCA period, the true up amount proposed by the Company in this case is $14.2 million higher than it should be. Staff maintains that the proposed adjustment represents an improvement in PCA accuracy and not a change in PCA methodology.

Given the complex nature of the adjustment calculations and the limited time for party review, Staff recommends that Company-proposed rates be approved beginning June 1, 2014. However, Staff further recommends that the Commission hold its decision on the $14.2 million adjustment so the parties can hold a workshop to evaluate the adjustment and its justification, and report back to the Commission. Once the parties have an opportunity to review the

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[4] To comply with Commission Order, Staff applied 95% sharing to the QF NPSE portion of the LCA.

adjustment and report back to the Commission, the PCA deferral balance can be adjusted as necessary and included in next year's PCA.

c. The Reconciliation of the True-up

The reconciliation of the true-up amount is the difference between what was approved to be collected or refunded when the PCA rate for last year's true-up was set, and what was actually collected or refunded. The reconciliation of the true-up assures the Company and its customers that the amount approved for recovery is the amount actually recovered.

Staff audited the amounts booked to the Reconciliation of the True-up, including the revenue sharing from Order No. 32821 and the transfer of the deferral balance from the previous PCA year, as well as verified the actual monthly collections and interest calculations and finds them to all be correct.

Table 3: True-Up Reconciliation

2012-13 Forecast True-Up	62,204,982
2011-12 True-Up of the True-Up Balance	(7,719,349)
Revenue Sharing (Order No. 32821 + interest)	(7,172,095)
Net Amount Set for Recovery/(Refund)	47,313,538
Collections from True-Up Rates	(28,593,706)
Interest	421,085
Sub-Total	(28,172,621)
True-Up Reconciliation	19,140,917

This is the amount recommended for recovery from customers by the Company and Staff. Dividing this amount by expected sales produces the true-up reconciliation rate of 0.1412 ¢/kWh. This calculation is shown on Attachment B, line 25.

Staff calculates the sum of all three of the true-up rate components to be 0.7305 ¢/kWh as proposed by Idaho Power.

2. Additional PCA Components

a. Revenue Sharing

In 2010, Commission Order No. 30978 established a mechanism that in part required Idaho Power to share revenue if the Company's actual Idaho jurisdictional year-end Return on

Equity ("ROE") exceeded 10.5% in the years 2009 through 2011. If revenue sharing was triggered, the Company was to share 50% of any earnings above 10.5% ROE with customers. For the years ending December 31, 2009 and 2010, revenue sharing was not triggered, as the Idaho jurisdictional year-end ROE was between 9.5% and 10.5%. Revenue sharing was triggered for the year ending December 31, 2011.

Order No. 32424 modified the revenue sharing mechanism and extended it through 2014. Order No. 32424 reduced the sharing level to 10%, with equal sharing between customers and the Company when the ROE is greater than 10% up to and including 10.5%. This customer portion of the "revenue sharing" benefit is a customer credit that is netted with the traditional PCA components to yield a combined rate that is set forth in Schedule 55. In addition, when the ROE exceeds 10.5%, the earnings above 10.5% continue to be shared, with customers receiving 75% of the earnings above 10.5%. The customer share of earnings above 10.5% will be applied to the Company's pension balancing accounts. This revenue sharing contribution reduces the amounts the Company would otherwise be allowed to collect from customers. Revenue sharing was triggered for the years ending December 31, 2012 and 2013.

In this year's filing, the Company calculates $24.1 million, after tax gross-up, of revenue to be shared with customers. The offset to the PCA is $7.6 million and the remaining $16.5 million is to be applied to the Company's pension balancing account. Idaho Power proposes to spread the PCA revenue sharing credit to customer classes based on each class's proportional share of the forecasted base revenue for the year beginning June 1, 2014. This is the same methodology used to allocate the revenue sharing in previous years. These proposed adjustments decrease rates by about 0.76% relative to current base revenues and are shown in Company Exhibit No. 4.[5] For the four special contract customers, the Company proposes they each receive a flat dollar-per-month credit during the PCA year. The proposed annual credits, as shown in Exhibit No. 4 are: Micron-$163,742; Simplot-$62,390; DOE-$80,750. These rates are included in Tariff Schedule 55, which is proposed to be effective June 1, 2014 and remain in effect for one year.

Staff traced every line item of this year's Additional Investment Tax Credit Analysis Worksheet[6] to the monthly financial statements provided by the Company for 2013. The

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[5] Tatum, DI Exhibit No. 4
[6] Tatum, DI Exhibit No. 3

Additional Investment Tax Credit Analysis Worksheets for 2012, September 2013 and Year End 2013 were reviewed for comparison purposes. The methodology was consistent across years and no material differences were noted. Staff also re-calculated the revenue sharing percentages for the total system as well as the Idaho allocation.

Staff reviewed the PCA class allocated revenue sharing for 2013 and 2014. Both years were calculated using the same methodology, which was consistent with Mr. Tatum's direct testimony,[7] and were based on each class's proportional share of the forecasted base revenues. The percent of revenue change for 2013 was 0.81%, and for 2014 it is 0.76%.

After reviewing the Company's Additional Investment Tax Credit Analysis Worksheet and supporting documentation, Staff believes the Company has correctly calculated and allocated shared revenues.

b. Mitigation

Staff reviewed Idaho Power's proposal to transfer from the energy efficiency tariff Rider to the PCA: (1) $16.0 million of 2014-2015 current and forecasted surplus funds; and (2) ongoing, annual $4.0 million from the rider to the PCA to maintain the revenue neutrality of moving $99.3 million of power supply expenses to base rates.

Staff reviewed the Company's forecasted energy efficiency revenues and expenditures through May 2015 and agrees that funds collected in excess of the energy efficiency expenses should be returned to customers. However, Staff believes it is inappropriate to collect money from customers for the express purpose of funding energy efficiency programs and then use those funds to offset increased expenses associated with the Company's supply-side resources, especially prospectively. On that basis, Staff makes two recommendations.

Staff believes that to the extent the Company does not spend the $16.0 million surplus on cost-effective energy efficiency, it should be refunded to customers as a reduction to the energy efficiency services portion of their bills rather than through the annual adjustment mechanism. Funds were collected from customers under the premise that they would be used for energy efficiency. To use those funds for any other purpose is inconsistent with the terms under which they were collected. Refunding the funds by reducing energy efficiency services assures

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[7] Tatum, DI page 20-21

customers that the funds collected through the Rider remain dedicated to the Company's energy efficiency efforts.

Staff has also verified the Company's calculation of the $4 million DSM Rider transfer necessary to maintain the revenue neutrality of the $99.3 million transfer of power supply costs into base rates for the current PCA year. Staff recommends that $20 million be returned to customers as a net reduction to the energy efficiency services portion of the bill for the upcoming PCA year, with the rates per customer class as shown in Column G of Company witness Wright's Exhibit No. 6. The financial effect on customers' bills is the same under both the Company and Staff's refund methods, but Staff's recommendation is consistent with how the energy efficiency funds were collected.

To ensure that future DSM rider surpluses do not occur, Staff recommends that the Company review the current DSM funding mechanism to determine if a normalized level of DSM expenses should be moved into base rates and the energy efficiency tariff Rider discontinued. In that scenario, actual DSM expenses would be tracked through the PCA and subject to true-up. If Idaho Power spends more or less than is collected in base rates, 100% of the difference would be collected through the PCA.

Shifting DSM expenses to base rates with true-up through the PCA assures that unspent Rider funds do not accrue in the future. Moving DSM expenses into base rates fulfills the "revenue neutral" requirement from Order No. 33000 without adjusting the DSM Rider balance annually until the next general rate case.

The change in base revenues with true-up through the PCA, effective June 1, 2014, will enable the Company to collect about $40 million through the tariff Rider, far surpassing its recent and projected DSM expenses. The Company's forecasted DSM expenses through May 2015 lead Staff to believe that the DSM balancing accounts will have a surplus indefinitely. With base expenses set closer to forecasted levels of expenditures— currently around $22 million— and deviations tracked though the PCA, customer funds will more closely align with the Company's energy efficiency efforts than they do under the current Rider mechanism.

Therefore, Staff recommends that: 1) $20 million in surplus energy efficiency tariff Rider funds be credited to customers as a reduction to the energy efficiency services portion of bills coincident with the 2014-2015 PCA; and 2) the Company assess whether moving forecasted base energy efficiency expenses from the tariff Rider to base rates, for annual reconciliation at 100%, serves the interest of customers.

3. <u>PCA Summary</u>

Staff has included two attachments that provide summary or historical information concerning the PCA. Staff Attachment G summarizes PCA expense amounts and rate components for this case. The attachment also shows amounts allocated to other jurisdictions and amounts shared with shareholders. Attachment H is a bar graph that shows the amount of each PCA since its inception. Attachment H only includes the amounts associated with the traditional PCA components of the Forecast, True-Up and Reconciliation of the True-Up.

PCA Review Constraints

The Commission and Staff are afforded 45 days from when the Company files its annual PCA for review and the issuance of a final order. The expedited processing of the case is necessary because power supply expenses must be forecasted in early spring and the timing of rate changes must coincident with the summer season. Because the forecast is primarily driven by snowpack, it is advantageous to base projected power supply costs on snowpack reports that reflect the best estimate of runoff, typically around April 1.

The complexity of the PCA continues to evolve, causing a compressed processing timeline that constrains a more complete evaluation of the filing. As long as the forecast component remains in place, the timeline will remain condensed. Staff believes some of the pressure associated with review would be alleviated if the Company filed its workpapers as part of its Application rather than after Staff or other parties have requested them. Doing so would benefit Staff and intervening parties by expediting the review process. Staff recommends the Commission direct the Company to provide all workpapers in functional format as part of its annual PCA filing.

C. Staff's Rate Calculations

Staff's base rate calculations are shown on Attachment I. Attachment I demonstrates that an equal ¢/kWh rate of 0.7320 ¢/kWh recovers the NPSE amount of approximately $99.3 million as ordered in Commission Order No. 33000.

Traditional PCA rates are calculated on Attachment B to these comments. The uniform 0.7305 ¢/kWh PCA rate surcharge is the sum of the three traditional PCA components (0.1609 + 0.4284 + 0.1412). This new PCA surcharge rate is a substantial decrease from the current rate of 1.2306 ¢/kWh.

The revenue sharing rate decrease of approximately $7.6 million is spread to the individual rate schedules on an equal percentage of base revenue basis. The rate spread reduces the revenue to all schedules by 0.76 %. The reduction is credited through the energy rates of each schedule. Attachment J shows these calculations. This process creates a different rate for each schedule as shown in Column F of the attachment. The Staff calculations agree with those presented by the Company.

As previously discussed, the Company proposes $20.0 million in rate mitigation. The amount would come from DSM Rider funds that can be broken into two parts. The first part is about $4.0 million that is expected to accrue to the account each year as a direct result of the base rate increase approved in Order No. 33000 and implemented as part of this case. The additional $16.0 million would come from unused tariff Rider funds. The $4.0 million amount is to be allocated and recovered on an equal ¢/kWh basis and the $16.0 million amount is to be allocated on an equal percent of base revenue basis. Attachment K shows these calculations. These are the same rates proposed by the Company. Staff recommends crediting the $20.0 million back to customers as a net amount on the Energy Efficiency Services line on each customer's bill.

Attachment L shows all Schedule 55 rates components.

The Company's tariff with the proposed rates is included as Attachment 1 to the Company's Application.

D. Customer Relations

Customer Notice and Press Release

Idaho Power filed copies of its press release and customer notice with its Application on April 15, 2014. Staff reviewed the press release and determined that it complies with the Commission's Procedural Rule 125, IDAPA 31.01.01.125. Staff has two primary concerns regarding the customer notice.

Staff is concerned that many customers will not receive timely notice of the Company's Application. Rule 125.03 provides that "Distribution of customer notices shall commence when the utility files its application or as soon as possible thereafter." Document design and the text of a customer notice are prepared in-house by Idaho Power and are finalized shortly before an application is filed. After filing, the Company conveys the document to a printing company in Boise. After printing, notices are shipped to Idaho Power's billing services contractor in California for inclusion in customer bills. Bills are then mailed to Idaho Power's customers using USPS bulk mail. According to Idaho Power, it normally takes 10 calendar days after an application is filed to complete the entire process. For this case, Idaho Power expedited the process, shaving three days from the usual time frame. The customer notice is being mailed with cyclical billings beginning on April 22 and ending May 21. Customers who are billed on the final day of the cycle (May 21) should receive their bills and notices within two business days (Friday, May 23).

This means that many customers will not receive notice of the case until after the comment filing deadline of May 16, 2014. Other customers who receive notice on or shortly before the comment deadline will not have a reasonable opportunity to prepare and file timely comments. To remedy this problem, the Commission can suspend the proposed effective date and extend the comment period. *See* § 61-622, *Idaho Code*. However, the fact that other changes affecting rates, e.g., the FCA and the switch from non-summer to summer rates, are linked to the same effective date (June 1) make it very difficult for the Commission to do so.

The Commission also has the discretion to accept and consider late-filed comments. Doing so will mitigate but not entirely resolve the problem created by untimely notification of customers. The Commission must issue its order in this case by Friday, May 30 in order to meet the Company's requested effective date. Monday, May 26, is a holiday (Memorial Day), which decreases the amount of time the Commission has to deliberate and reach a decision. Because there is no mail delivery on May 26, there is one less day for the Commission to receive comments mailed by customers. Given the circumstances surrounding the expedited treatment of this case, Staff recommends that the Commission accept late-filed comments, recognizing the probability that the Commission will be unable to take into consideration comments filed by customers whose bills are issued at the end of the billing cycle.

Staff is also concerned that the Company includes information about its fuel mix in its PCA customer notice. Although Staff supports the Company's efforts to provide resource information to customers, notices about proposed rate changes are not the appropriate vehicle. The Commission requires that the information included in customer notices be "clearly identified, easily understood, and pertain only to the proposed rate change." *See* Rule 125.03, Rules of Procedure.

Investor-owned utilities in Idaho, including Idaho Power, voluntarily provide a resource portfolio report to customers annually. The 2007 Idaho Energy Plan recommended that utilities provide this information to customers, and the 2012 Idaho Energy Plan recognized the utilities' compliance with this recommendation. *See* pp. 54 & 55, 2012 Idaho Energy Plan. To comply with both the Idaho Energy Plan and the Commission's Rule 125.03, Staff recommends that Idaho Power provide this valuable information through billing inserts, not customer notices pertaining to proposed rate changes.

<u>Customer Comments</u>

As of May 12, 2014, four comments were received from customers regarding the PCA. All of the comments opposed the proposed increase. One customer mentioned a decrease in usage after adding insulation and energy-efficient heating and air conditioning; despite that fact, the bills increased. Another customer questioned the need for a rate increase given the current water surplus. Customers also addressed the Annual Adjustment Mechanism, tiered rates, executive compensation, and hardships caused by rising electric bills.

In both its press release and customer notice, Idaho Power describes the impact of its proposal on rates. Part of the Company's proposal is to use $20 million in energy efficiency funds to offset increased power supply expenses. This one-time rate mitigation measure is factored into the calculation of the total impact the Company's proposal has on rates. Both the total dollar amount and overall percentage increase is provided, as well as a breakdown of the percentage increase for each major customer class. While the Company's press release and customer notice both mention the Company's proposal to offset power expenses by using energy efficiency funds, it does not quantify the overall percentage increase or provide a breakdown by customer class. As a result, customers are not alerted to the gross rate impact of the Company's request should the Commission decide not to accept the Company's rate mitigation proposal. To enable customers to fully understand possible rate impacts, Staff recommends that in future cases where rate mitigation is proposed, the Company should explain what the impact will be with and without rate mitigation.

STAFF RECOMMENDATIONS

Staff recommends that the Commission approve the base rates proposed by Idaho Power Company. Staff also recommends that the Commission approve the revenue sharing amounts proposed by the Company; specifically, PCA revenue sharing of $7,602,043 and a pension balancing account contribution of $16,512,853.

Staff recommends that the Commission approve Schedule 55 rates as filed in Attachment 1 to the Company's Application. Staff recommends that new base rates and updated Schedule 55 rates be effective June 1, 2014.

Staff further recommends that the Commission defer any consideration of Staff's proposed adjustment to the True-up deferral balance of $14,196,038 so the parties can hold a workshop to evaluate it and then report back to the Commission. The PCA deferral balance can then be adjusted and included in next year's PCA.

Staff also recommends that: 1) $20 million in surplus energy efficiency tariff rider funds be credited to customers as a reduction to the energy efficiency services portion of bills coincident with the 2014-2015 PCA; and 2) the Company assess whether moving forecasted base energy efficiency expenses from the tariff Rider to base rates, for annual reconciliation at 100%, serves the interest of customers.

Staff further recommends that the Commission direct the Company to provide all workpapers in functional format as part of its future annual PCA filings.

Staff recommends that the Commission accept late-filed comments from customers in this case.

To comply with both the Idaho Energy Plan and the Commission's Rule 125.03, Staff recommends that Idaho Power provide resource portfolio information to customers through billing inserts rather than customer notices pertaining to proposed rate changes.

Staff recommends approval of the change to Schedule 89 rates as proposed by Idaho Power.

Respectfully submitted this 16th day of May 2014.

Karl T. Klein
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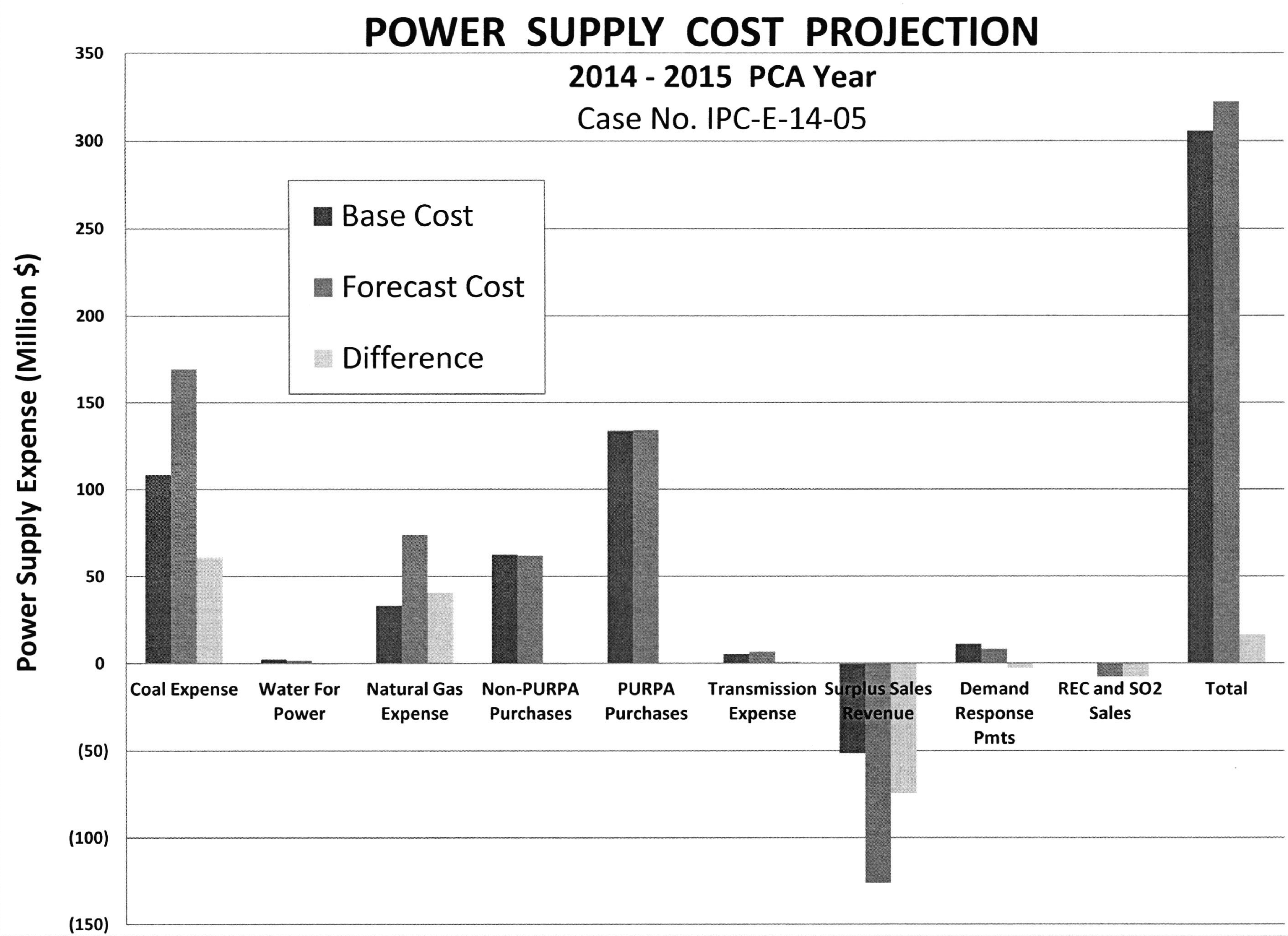

POWER SUPPLY COST PROJECTION
2014 - 2015 PCA Year
Case No. IPC-E-14-05
Power Supply Expense (Million $)
350
300
250
200
150
100
50
0
(50)
(100)
(150)
Base Cost
Forecast Cost
Difference
Coal Expense
Water For Power
Natural Gas Expense
Non-PURPA Purchases
PURPA Purchases
Transmission Expense
Surplus Sales Revenue
Demand Response Pmts
REC and SO2 Sales
Total

2014-2015 PCA - Twenty-Second Annual
IPC-E-14-05
Staff Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line	Description	Units	Base	Forecast	Difference	Rate
1	**Forecast 2013-2014:**					
2	PCA Expense (95%)	($)	160,578,735	187,593,267		
3	Hoku First Block Revenue	($)		0		
4	Difference	($)		187,593,267	27,014,532	
5	Sharing Percentage	(%)			0.95	
6	Shared Difference	($)			25,663,805	
7	Normalized System Firm Sales	(MWH)			14,200,871	
8	Rate for 95 % Items	(¢/kWh)			0.1807	0.1807
9						
10	PCA Expense (PURPA at 100%)	($)	133,853,869	134,142,386	288,517	
11	Normalized System Firm Sales	(MWH)			14,200,871	
12	Rate for PURPA	(¢/kWh)			0.0020	0.0020
13						
14	Demand Response Incentives (100%)	($)	11,252,265	8,290,603	(2,961,662)	
15	Idaho Jurisdictional Sales	(MWH)			13,558,865	
16	Rate for Demand Response	(¢/kWh)			(0.0218)	(0.0218)
17						
18	Total Forecast Rate	(¢/kWh)				**0.1609**
19						
20						
21			($)	(MWh)	($/MWh)	(¢/kWh)
22						
23	**True-Up of 2013-2014:**		58,088,876	13,558,865	4.284	**0.4284**
24						
25	**True-Up of the True-Up:**		19,140,917	13,558,865	1.4117	**0.1412**
26						
27	**PCA Rates:**					
28	PCA Rate Adjustment From Base	(¢/kWh)				**0.7305**
29	PCA Rate Currently in Effect	(¢/kWh)				1.2306
30	Difference - Last Year to This Year	(¢/kWh)				(0.5001)
31						
32	Note: Negative rates and amounts indicate benefits to ratepayers.					
33						
34						
35	**Expected PCA Revenues:**		Rate	Energy	Revenue	
36			($/MWh)	(MWh)	($)	
37						
38	Forecast Revenue		1.609	13,558,865	21,816,214	
39	True Up Revenue		4.284	13,558,865	58,086,178	
40	True Up of True Up Revenue		1.412	13,558,865	19,145,117	
41	Total		7.305		99,047,509	
42						
43		13,558,865,000	Company Estimate of 2014/2015 Idaho Jurisdictional sales			
		14,200,871,000	Company Estimate of 2014/2015 normalized system firm sales			

NOTES:

Rates are for a one year recovery period
Rates exclude Revenue Sharing

TRUE-UP CALCULATIONS FOR 2013 - 2014
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-14-05
(Base Costs are Redistributed)

1			2013	2013	2013	2013	2013	2013	2013
2	DESCRIPTION	Units	APR	MAY	JUN	JUL	AUG	SEPT	OCT
3	**PCA Forecast Revenue**								
4	Actual Idaho Jurisd. Sales*	MWh	922,125	931,654	350,250	1,506,796	1,586,090	1,370,093	1,002,511
5	Forecast Rate	$/MWh	5.099	5.099	8.258	8.258	8.258	8.258	8.258
6	Revenue	$	4,701,915	4,750,504	2,892,365	12,443,121	13,097,931	11,314,228	8,278,736
7									
8	**Load Change Adjustment**								
9	Actual System Firm Load - Adjusted	MWh	1,076,204	1,328,511	1,552,985	1,793,750	1,654,552	1,192,855	1,068,601
10	Normalized Firm Load	MWh	1,047,064	1,271,705	1,393,674	1,744,091	1,586,231	1,279,154	1,098,456
11	Load Change	MWh	29,140	56,806	159,311	49,659	68,321	(86,299)	(29,855)
12	Expense Adjustment	$	(514,030)	(1,002,058)	(2,810,246)	(875,985)	(1,205,182)	1,522,314	526,642
13									
14	**Non-QF PCA**								
15	ACTUAL:								
16	Water Leases	$	0	0	101,661	571,450	0	0	0
17	Fuel Expense - Coal	$	8,027,505	10,281,418	13,890,512	14,894,959	16,158,574	12,711,963	12,721,007
18	Fuel Expense - Gas	$	1,486,610	2,699,000	5,400,087	7,146,220	7,870,882	5,974,810	1,454,620
19	Non-Firm Purchases	$	3,743,953	4,453,123	5,532,095	14,646,694	10,455,494	5,294,844	5,661,427
20	Third Party Transmission	$	257,799	357,848	763,792	897,309	796,450	512,842	492,775
21	Surplus Sales	$	(1,442,293)	(1,223,681)	(1,450,264)	(2,397,724)	(2,031,595)	(6,426,201)	(6,225,007)
22	Hoku First Block Energy	$	0	0	0	0	0	0	0
23	Expense Adjustment	$	(514,030)	(1,002,058)	(2,810,246)	(875,985)	(1,205,182)	1,522,314	526,642
24	Sub-Total	$	11,559,544	15,565,649	21,427,637	34,882,923	32,044,622	19,590,572	14,631,464
25									
26	BASE:								
27	Water for Power (Leases)	$	123,719	122,164	155,409	195,168	206,542	184,523	132,222
28	Fuel Expense - Coal	$	11,311,629	11,169,485	14,209,042	17,844,222	18,884,185	16,870,940	12,089,048
29	Fuel Expense - Gas	$	3,513,672	3,469,518	4,413,680	5,542,857	5,865,895	5,240,531	3,755,157
30	Non-Firm Purchases	$	3,079,041	3,040,349	3,867,721	4,857,222	5,140,301	4,592,293	3,290,655
31	Third Party Transmission	$	558,976	551,952	702,154	881,790	933,181	833,695	597,393
32	Hoku First Block Energy	$	(1,618,436)	(1,598,098)	(2,032,990)	(2,553,101)	(2,701,896)	(2,413,847)	(1,729,667)
33	Surplus Sales	$	(8,451,355)	(8,345,154)	(10,616,124)	(13,332,107)	(14,109,103)	(12,604,931)	(9,032,194)
34	Sub-Total	$	8,517,246	8,410,216	10,698,892	13,436,051	14,219,105	12,703,204	9,102,614
35									
36	Change From Base	$	3,042,298	7,155,433	10,728,745	21,446,872	17,825,517	6,887,368	5,528,850
37	Emission Allowance Sales Credit	$	0	0	0	0	0	0	(24,000)
38	Renewable Energy Credit Sales	$	(465,967)	1,106	(14,004)	(2,428)	(8,524)	330	(8,370)
39	Sub-Total	$	2,576,331	7,156,539	10,714,742	21,444,444	17,816,993	6,887,698	5,496,480
40									
41	Deferral (Shared and Allocated)	$	2,325,139	6,458,776	9,670,054	19,353,611	16,079,836	6,216,147	4,960,574
42									
43	**Demand Response Incentive Pmts.**								
44	Actual	$	42	0	878,814	2,198,386	834,126	283,952	7,764
45	Base	$	761,286	751,719	956,285	1,200,937	1,270,927	1,135,434	813,607
46	Change From Base	$	(761,244)	(751,719)	(77,471)	997,449	(436,801)	(851,482)	(805,843)
47	Deferral	$	(761,244)	(751,719)	(77,471)	997,449	(436,801)	(851,482)	(805,843)
48									
49	**QF Deferral**								
50	Actual (incl. Net Metering & Raft River	$	10,572,548	10,908,936	11,681,713	12,831,995	12,662,857	12,673,490	10,763,930
51	Base	$	4,252,292	4,198,857	5,341,493	6,708,038	7,098,983	6,342,160	4,544,541
52	Change From Base	$	6,320,256	6,710,079	6,340,220	6,123,957	5,563,874	6,331,330	6,219,389
53	Deferral (Allocated)	$	6,004,243	6,374,575	6,023,209	5,817,759	5,285,681	6,014,763	5,908,420
54									
55	**Total Deferral** (-6+41+47+53)	$	2,866,223	7,331,128	12,723,428	13,725,698	7,830,785	65,200	1,784,415
56									
57	**Principal Balances**								
58	Beginning Balance	$	0	2,866,223	10,197,351	22,920,779	36,646,477	44,477,262	44,542,462
59	Amount Deferred	$	2,866,223	7,331,128	12,723,428	13,725,698	7,830,785	65,200	1,784,415
60	Ending Balance	$	2,866,223	10,197,351	22,920,779	36,646,477	44,477,262	44,542,462	46,326,877
61									
62	**Interest Balances**								
63	Accrual thru Prior Month	$	0	0	9,915	30,452	58,919	82,773	97,464
64	Interest @ 1% per Year	$	0	9,915	20,537	28,468	23,853	14,692	14,014
65	Prior Month's Interest Adj.	$	0	0	0	0	0	0	0
66	Total Current Month Interest	$	0	9,915	20,537	28,468	23,853	14,692	14,014
67	Interest Accrued to Date	$	0	9,915	30,452	58,919	82,773	97,464	111,478
68	**Balance (True-Up & Interest)**	$	2,866,223	10,207,266	22,951,230	36,705,396	44,560,035	44,639,926	46,438,355
69									
70	**True-Up of the True-Up**								
71	True-Up Revenues (Collections)	$	(3,426,815)	(3,833,037)	(1,751,527)	5,240,025	5,554,916	4,806,213	3,532,232
72									
73	Beginning Balance	$	(7,719,349)	57,957,853	54,667,091	56,458,200	51,265,223	45,753,028	40,984,943
74	Adjustments:								
75	2012-13 PCA Transfer (ON 32821)	$	62,204,982	0	0	0	0	0	0
76	Revenue Sharing ON 32821	$	0	(7,166,126)	(5,969)	0	0	0	0
77									
78	Sub-Total	$	54,485,633	50,791,728	54,661,122	56,458,200	51,265,223	45,753,028	40,984,943
79	Interest @ 1% per Year	$	45,405	42,326	45,551	47,049	42,721	38,128	34,154
80	Revenue Applied to Interest	$	45,405	42,326	45,551	47,049	42,721	38,128	34,154
81	Revenue Applied to Balance	$	(3,472,220)	(3,875,364)	(1,797,078)	5,192,977	5,512,195	4,768,086	3,498,078
82	**True-Up of the True-Up Balance**	$	57,957,853	54,667,091	56,458,200	51,265,223	45,753,028	40,984,943	37,486,865

Note: Negative amounts indicate benefit to ratepayers

Level of Customer Sharing	%	95%	95%	95%	95%	95%	95%	95%
Idaho Jurisd. Energy Allocator	%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%	95.0%
Load Change Adjustment Rate	$/MWh	17.64	17.64	17.64	17.64	17.64	17.64	17.64
Interest Rate	%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Forecast Rate	$/MWh	5.0990	5.0990	8.2580	8.2580	8.2580	8.2580	8.2580

TRUE-UP CALCULATIONS FOR 2013 - 2014
FOR
IDAHO POWER COMPANY PCA
CASE NO. IPC-E-14-05
(Base Costs are Redistributed)

DESCRIPTION	Units	2013 NOV	2013 DEC	2014 JAN	2014 FEB	2014 MAR	TOTALS
PCA Forecast Revenue							
Actual Idaho Jurisd. Sales*	MWh	938,372	1,093,779	1,180,245	1,111,808	950,799	12,944,522
Forecast Rate	$/MWh	8.258	8.258	8.258	8.258	8.258	
Revenue	$	7,749,076	9,032,427	9,746,463	9,181,310	7,851,698	101,039,775
Load Change Adjustment							
Actual System Firm Load - Adjusted	MWh	1,102,929	1,368,173	1,282,108	1,083,454	1,063,476	15,567,598
Normalized Firm Load	MWh	1,131,972	1,358,395	1,346,312	1,139,208	1,134,875	15,531,137
Load Change	MWh	(29,043)	9,778	(64,204)	(55,754)	(71,399)	36,461
Expense Adjustment	$	512,319	(172,484)	1,132,559	983,501	1,259,478	(643,172)
Non-QF PCA							
ACTUAL:							
Water Leases	$	0	0	0	33,300	0	706,411
Fuel Expense - Coal	$	15,084,510	16,190,309	17,881,323	14,983,221	8,170,369	160,995,670
Fuel Expense - Gas	$	4,857,341	8,159,706	6,989,544	5,657,873	1,532,113	59,228,806
Non-Firm Purchases	$	6,923,618	9,030,513	4,052,609	4,854,879	3,874,439	78,523,687
Third Party Transmission	$	346,526	343,673	338,568	325,776	327,362	5,760,718
Surplus Sales	$	(9,125,878)	(7,451,787)	(8,385,471)	(9,811,088)	(10,813,742)	(66,784,731)
Hoku First Block Energy	$	0	0	0	0	0	0
Expense Adjustment	$	512,319	(172,484)	1,132,559	983,501	1,259,478	(643,172)
Sub-Total	$	18,598,435	26,099,929	22,009,131	17,027,462	4,350,020	237,787,389
BASE:							
Water for Power (Leases)	$	122,643	144,891	160,651	147,407	133,301	1,828,640
Fuel Expense - Coal	$	11,213,235	13,247,390	14,688,304	13,477,403	12,187,860	167,192,743
Fuel Expense - Gas	$	3,483,108	4,114,967	4,562,550	4,186,415	3,785,851	51,934,201
Non-Firm Purchases	$	3,052,258	3,605,958	3,998,176	3,668,568	3,317,552	45,510,094
Third Party Transmission	$	554,113	654,633	725,838	666,000	602,275	8,262,000
Hoku First Block Energy	$	(1,604,358)	(1,895,399)	(2,101,561)	(1,928,309)	(1,743,805)	(23,921,467)
Surplus Sales	$	(8,377,841)	(9,897,636)	(10,974,199)	(10,069,488)	(9,106,021)	(124,916,153)
Sub-Total	$	8,443,158	9,974,804	11,059,759	10,147,996	9,177,013	125,890,058
Change From Base	$	10,155,277	16,125,125	10,949,372	6,879,466	(4,826,993)	111,897,331
Emission Allowance Sales Credit	$	0	0	0	0	0	(24,000)
Renewable Energy Credit Sales	$	(57,748)	329	(397,331)	(657,345)	(264,940)	(1,874,892)
Sub-Total		10,097,529	16,125,454	10,552,041	6,222,121	(5,091,932)	109,998,439
Deferral (Shared and Allocated)	$	9,113,020	14,553,223	9,523,217	5,615,464	(4,595,469)	99,273,591
Demand Response Incentive Pmts.							
Actual	$	0	10	(5,880)	0	0	4,197,214
Base	$	754,664	891,565	988,540	907,045	820,257	11,252,266
Change From Base	$	(754,664)	(891,555)	(994,420)	(907,045)	(820,257)	(7,055,052)
Deferral	$	(754,664)	(891,555)	(994,420)	(907,045)	(820,257)	(7,055,052)
QF Deferral							
Actual (incl. Net Metering & Raft River	$	10,063,745	11,107,040	10,292,764	10,529,045	8,915,030	133,003,093
Base	$	4,215,303	4,979,987	5,521,659	5,066,454	4,581,687	62,851,454
Change From Base	$	5,848,442	6,127,053	4,771,105	5,462,591	4,333,343	70,151,639
Deferral (Allocated)	$	5,556,020	5,820,701	4,532,549	5,189,462	4,116,675	66,644,057
Total Deferral (-6+41+47+53)	$	6,165,299	10,449,941	3,314,883	716,570	(9,150,749)	57,822,822
Principal Balances							
Beginning Balance	$	46,326,877	52,492,176	62,942,117	66,257,000	66,973,570	
Amount Deferred	$	6,165,299	10,449,941	3,314,883	716,570	(9,150,749)	57,822,822
Ending Balance	$	52,492,176	62,942,117	66,257,000	66,973,570	57,822,822	
Interest Balances							
Accrual thru Prior Month	$	111,478	129,650	151,697	181,959	219,185	
Interest @ 1% per Year	$	18,172	22,047	30,262	37,226	46,869	266,054
Prior Month's Interest Adj.	$	0	0	0	0	0	0
Total Current Month Interest	$	18,172	22,047	30,262	37,226	46,869	266,054
Interest Accrued to Date	$	129,650	151,697	181,959	219,185	266,054	
Balance (True-Up & Interest)	$	52,621,826	63,093,814	66,438,959	67,192,755	58,088,876	**58,088,876**
True-Up of the True-Up							
True-Up Revenues (Collections)	$	3,301,969	3,826,256	4,120,942	3,887,370	3,335,162	28,593,706
Beginning Balance	$	37,486,865	34,216,135	30,418,393	26,322,799	22,457,365	(7,719,349)
Adjustments:							
2012-13 PCA Transfer (ON 32821)	$	0	0	0	0	0	62,204,982
Revenue Sharing ON 32821	$	0	0	0	0	0	(7,172,095)
Sub-Total	$	37,486,865	34,216,135	30,418,393	26,322,799	22,457,365	47,313,538
Interest @ 1% per Year	$	31,239	28,513	25,349	21,936	18,714	
Revenue Applied to Interest	$	31,239	28,513	25,349	21,936	18,714	421,085
Revenue Applied to Balance	$	3,270,730	3,797,742	4,095,593	3,865,435	3,316,448	28,172,621
True-Up of the True-Up Balance	$	34,216,135	30,418,393	26,322,799	22,457,365	19,140,917	**19,140,917**

Note: Negative amounts indicate benefit to ratepayers

Level of Customer Sharing	95%	95%	95%	95%	95%
Idaho Jurisd. Energy Allocator	95.0%	95.0%	95.0%	95.0%	95.0%
Load Change Adjustment Rate	17.64	17.64	17.64	17.64	17.64
Interest Rate	1.00%	1.00%	1.00%	1.00%	1.00%
Forecast Rate	8.2580	8.2580	8.2580	8.2580	8.2580

Staff Line Loss Analysis

Base Idaho Sales (June '12 thru May '13)	13,172,433	Established in Case IPC-E-12-14
Base Idaho Load at Generation used in LCAR (Jan '11 thru Dec '11)	14,822,063	Established in Case IPC-E-12-14
Line Loss embedded in Base Rates	**11.13%**	
Actual System Sales	14,494,305	See Staff Production Request #8, IPC-E-14-05
Actual System Load at Generation used in LCA	15,567,598	See Staff Production Request #6, IPC-E-14-05
Actual Line Loss	**6.89%**	
Line Loss Difference	**4.24%**	

Staff Base Rate Over-collection Adjustments - IPC-E-14-05
Deferral Period - April '13 through Mar '14

		Jurisdictional Allocation =	95%
Adjustment for Recovery of Non-QF NPSE	**System**	**Idaho**	**Adjustment Total**
Actual Idaho Non-QF NPSE ($)	238,430,561		**226,509,033**
Recovery of Actual Idaho Non-QF NPSE			
Recovery of Actual Idaho Non-QF NPSE through Base Rates			
Idaho Non-QF NPSE Cost embedded in Base Rates ($)[1]	125,890,058	119,595,555	
Annual Idaho Base Sales (sales @ customer meter - MWh)		13,172,433	
Non-QF NPSE Base Rate ($/MWh)		9.079	
Idaho Actual Sales (sales @ customer meter - MWh)		13,847,795	
Revenue Collected through Base Rates ($)		125,727,327	125,727,327
Recovery of Actual Idaho Non-QF NPSE through PCA			
Company Proposed Non-QF NPSE Deferral (before sharing - $)	112,540,503		106,913,478
Non-QF NPSE portion of LCAR ($/MWh)	8.10		
Load Change (MWh)	36,461		
Company Proposed LCA Deferral - NPSE portion only ($ - before sharing)	(295,341)		(280,574)
Total Recovery of Actual Non-QF NPSE ($)			**232,360,231**
Over/(Under) Collection before sharing ($)			**5,851,198**
Over/(Under) Collection with sharing ($)	**Sharing =**	95%	**5,558,638**

[1] Amounts were set in IPC-E-12-14

		Jurisdictional Allocation =	95%
Adjustment for Recovery of Energy-Classified Fixed Production Cost	**System**	**Idaho**	**Adjustment Total**
Actual Idaho Energy-Classified Fixed Production Cost ($)[2]		109,080,535	**109,080,535**
Recovery of Idaho Energy-Classified Fixed Production Cost			
Recovery of Actual Energy-Classified Fixed Production Cost through Base Rates			
Idaho Energy-Classified Fixed Production Cost embedded in Base Rates ($)[3]		109,080,535	
Idaho Base Sales @ meter (MWh)		13,172,433	
Energy-Classified Fixed Production Cost Base Rate ($/MWh)		8.28	
Idaho Actual Sales @ meter (MWh)		13,847,795	
Revenue Collected through Base Rates ($)		114,673,192	114,673,192
Recovery of Energy-Classified Fixed Production Cost through PCA			
Fixed Cost portion of LCAR ($/MWh)	7.36		
Load Change (MWh)	36,461		
Company Proposed LCA Deferral - Fixed cost portion only ($ - before sharing)	(268,329)		(254,912)
Total Recovery of Idaho Fixed Cost Portion of Energy Classified Production Revenue Requirement			**114,418,279**
Over/(Under) Collection before sharing ($)			**5,337,745**
Over/(Under) Collection with sharing ($)	**Sharing =**	95%	**5,070,857**

[2] Assumes the fixed cost portion of Idaho Energy-classified Production Revenue Requirment embedded in Base Rates are equal to Actual Cost.

[3] This amount is the total LCAR revenue requirement of $261,437,727 (T. Tatum, DI, IPC-E-12-14, Exhibit No.4) net of Idaho base QF NPSE of $32,295,844 and Non-QF NPSE of $120,061,348 authorized in case IPC-E-12-14.

Adjustment for QF Deferral	System	Idaho	Adjustment Total
		Jurisdictional Allocation =	95%
Actual QF NPSE	133,003,093		**126,352,938**
Recovery of QF NPSE			
Recovery of QF NPSE in Base Rates			
QF NPSE Embedded in Base Rates ($)	62,851,454	59,708,881	
Idaho Base Sales @ meter (MWh)		13,172,433	
QF NPSE Base Rate ($/MWh)		4.53	
Idaho Actual Sales @ meter without replacement (MWh)		13,847,795	
Revenue Recovered through Base Rates ($)		62,770,209	62,770,209
Recovery of QF NPSE through PCA			
Company Proposed QF Deferral ($ - before sharing)	70,151,639		66,644,057
QF NPSE portion of LCAR ($/MWh)	2.18		
Load Change (MWh)	36,461		
Company Proposed LCA Deferral - QF NPSE portion only ($ - before sharing)	(79,445)		
Sharing for LCAR only	95%		
Company Proposed LCA Deferral - QF NPSE portion only ($ - after sharing)	(75,473)		(71,699)
Total Recovery of QF NPSE ($)			**129,342,567**
Over/(Under) Collection before sharing ($)			**2,989,629**
Over/(Under) Collection with sharing ($)	**Sharing =**	100%	**2,989,629**

Adjustment for DSM Incentive Deferral	System	Idaho	Adjustment Total
		Jurisdictional Allocation =	100%
Actual DSM Incentive Cost		4,197,214	**4,197,214**
Recovery of DSM Incentive Cost			
Recovery of DSM Cost in Base Rates			
Idaho DSM Cost Embedded in Base Rates ($)		11,252,266	
Idaho Base Sales @ meter (MWh)		13,172,433	
DSM Cost Base Rate ($/MWh)		0.85	
Idaho Actual Sales @ meter (MWh)		13,847,795	
Revenue collected through Base Rates ($)		11,829,180	11,829,180
Recovery of DSM Cost through PCA			
Company Proposed DSM Deferral ($ - before sharing)		(7,055,052)	(7,055,052)
Total Recovery of Actual DSM Incentive Cost ($)			**4,774,128**
Over/(Under) Collection before sharing ($)			**576,914**
Over/(Under) Collection with sharing ($)	**Sharing =**	100%	**576,914**
Total Over Collection Adjustment ($)			**14,196,038**

Note: The sum of the Non-QF NPSE, QF NPSE, and fixed cost LCAR rates is identical to the $17.64/MWh authorized rate used in the Company's filing.

Breakdown of LCAR used to Calculate Staff's Adjustments

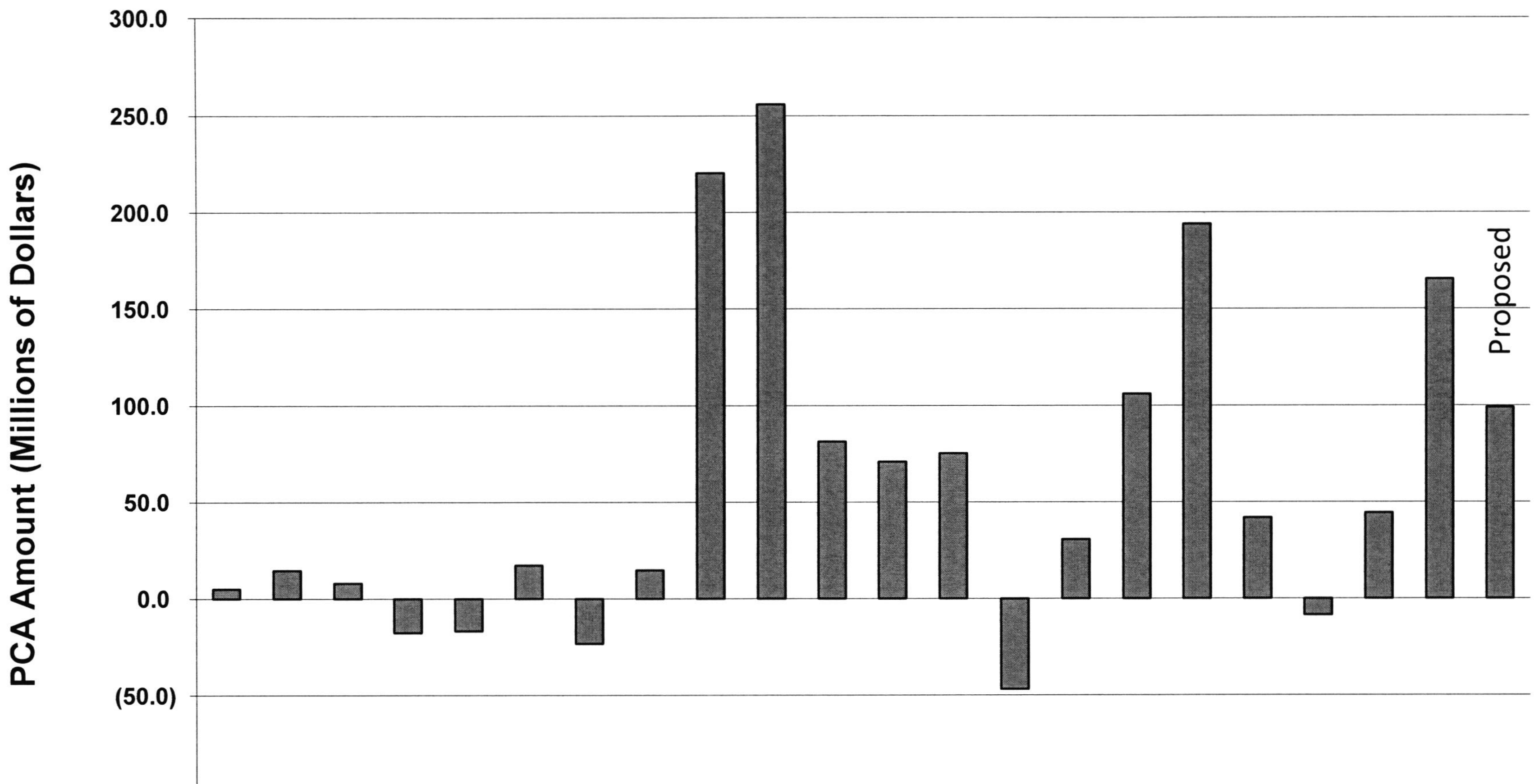
Base Idaho Jurisdiction Energy Classified Production Expense (QF NPSE, Non-QF NPSE, fixed cost)	261,437,727	See T. Tatum, DI, IPC-E-12-14, Exhibit No.4
Idaho Jurisdictional Load	14,822,063	See T. Tatum, DI, IPC-E-12-14, Exhibit No.4
Authorized LCAR	**17.64**	See T. Tatum, DI, IPC-E-12-14, Exhibit No.4
Base Idaho Non-QF NPSE	120,061,348	See Company Exhibit No. 5
Idaho Jurisdictional Load	14,822,063	See T. Tatum, DI, IPC-E-12-14, Exhibit No.4
Non-QF NPSE portion of LCAR	**8.10**	
Base Idaho QF NPSE	59,941,432	See Company Exhibit No. 5
QF Energy-Classified Allocation %	53.879%	Allocation indicated in Staff Production Request No. 9
Base Idaho Energy Classified QF NPSE	32,295,844	
Idaho Jursidictional Load	14,822,063	See T. Tatum, DI, IPC-E-12-14, Exhibit No.4
QF NPSE portion of LCAR	**2.18**	
Base Idaho Jurisdiction Energy Classified Production Expense (QF NPSE, Non-QF NPSE, fixed cost)	261,437,727	See T. Tatum, DI, IPC-E-12-14, Exhibit No.4
Base Idaho Non-QF NPSE	(120,061,348)	From above
Base Idaho Energy Classified QF NPSE	(32,295,844)	From above
Fixed Cost Portion of Energy Classified Production Expense	109,080,535	
Idaho Jurisdictional Load	14,822,063	See T. Tatum, DI, IPC-E-12-14, Exhibit No.4
Fixed Cost Portion of LCAR	**7.36**	
Sum Check	**17.64**	

Power Cost Adjustment Summary
Case No. IPC-E-14-05
(Base Costs are Redistributed)

Description	Projection or Actual ($)	Base ($)	Difference or Initial Amount ($)	Allocated to Other Jurisdictions ($)	Shared with Shareholders ($)	Idaho Customer Revenue Requirement ($)	**Idaho PCA Rates (¢/kWh)**
Forecast or Projection (2014-2015)	Projection	Base	Difference				
Acct. 501 - Coal	169,424,879	108,503,180	60,921,699	3,046,085	2,893,781	54,981,833	
Acct. 536 - Water for Power	1,751,000	2,380,597	(629,597)	(31,480)	(29,906)	(568,211)	
Acct. 547 - Natural Gas	73,941,673	33,367,563	40,574,110	2,028,706	1,927,270	36,618,134	
Acct. 555 - Purchased Power (Non- PURPA)	61,996,853	62,606,593	(609,740)	(30,487)	(28,963)	(550,290)	
Acct. 565 - Transmission Wheeling	6,645,775	5,455,955	1,189,820	59,491	56,516	1,073,813	
Acct. 447 - Opportunity Sales Revenues	(126,166,913)	(51,735,153)	(74,431,760)	(3,721,588)	(3,535,509)	(67,174,663)	
Acct. 442 - Hoku First Block Energy Revenue	0	0	0	0	0	0	0.1807
Acct. 555 - Purchased Power (PURPA)	134,142,386	133,853,869	288,517	14,426	0	274,091	0.0020
Demand Response Incentive Payments	8,290,603	11,252,265	(2,961,662)	0	0	(2,961,662)	(0.0218)
Sub-Total	330,026,256	305,684,869	24,341,387	1,365,152	1,283,190	21,693,044	**0.1609**
True Up (2013-2014)	Actual	Base	Difference				
Revenue from Forecast Rate	101,039,775	0	101,039,775	0	0	101,039,775	
Load Change Adjustment	(643,172)	0	(643,172)	(32,159)	(30,551)	(580,463)	
Acct. 501 - Coal	160,995,670	167,192,743	(6,197,073)	(309,854)	(294,361)	(5,592,858)	
Acct. 536 - Water for Power	706,411	1,828,640	(1,122,229)	(56,111)	(53,306)	(1,012,811)	
Acct. 547 - Natural Gas	59,228,806	51,934,201	7,294,605	364,730	346,494	6,583,381	
Acct. 555 - Purchased Power (Non- PURPA)	78,523,687	45,510,094	33,013,593	1,650,680	1,568,146	29,794,768	
Acct. 565 - Transmission Wheeling	5,760,718	8,262,000	(2,501,282)	(125,064)	(118,811)	(2,257,407)	
Acct. 447 - Opportunity Sales Revenues	(66,784,731)	(124,916,153)	58,131,422	2,906,571	2,761,243	52,463,609	
Acct. 442 - Hoku First Block Energy Revenue	0	(23,921,467)	23,921,467	1,196,073	1,136,270	21,589,124	
Acct. 555 - Purchased Power (PURPA)	133,003,093	62,851,454	70,151,639	3,507,582	0	66,644,057	
Emission Allowance Sales Credit	(24,000)	0	(24,000)	(1,200)	(1,140)	(21,660)	
REC Sales	(1,874,892)	0	(1,874,892)	(93,745)	(89,057)	(1,692,090)	
Interest During Deferral Period	266,054	0	266,054	0	0	266,054	
Demand Response Incentive Payments	4,197,214	11,252,266	(7,055,052)	0	0	(7,055,052)	
Sub-Total	272,315,083	199,993,778	72,321,305	9,007,504	5,224,926	58,088,876	**0.4284**
True Up of the True Up (Reconciliation of the True Up)			Initial Amount				
Unrecovered True Up of the True Up Amount Carried Forward			(7,719,349)			(7,719,349)	
2012 PCA True-Up Amount - Transferred			62,204,982			62,204,982	
Other Adjustments:							
Revenue Sharing - O.N 32558			(7,172,095)			(7,172,095)	
Interest During Amortization			421,085			421,085	
Revenue from True Up & True Up of the True Up Rates			(28,593,706)			(28,593,706)	
Sub-Total			19,140,917	0	0	19,140,917	**0.1412**
Total Power Cost Adjustment (PCA)							**0.7305**

Attachment G
Case No. IPC-E-14-05
Staff Comments
05/16/14

HISTORY OF IDAHO POWER PCA AMOUNTS



	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
PCA Amounts	5.1	14.7	8.1	(17.6)	(16.7)	17.3	(23.2)	14.8	220.2	255.9	81.3	70.8	75.2	(46.8)	30.7	106.0	194.0	41.9	(8.5)	44.4	165.6	99.0

PCA Year

Idaho Power Company - Base Rate Increase (Order No. 33000)
Calculation of Revenue Impact
Case No. IPC-E-14-05

Line No	Tariff Description	Rate Sch. No.	(A) Average Number of Customers	(B) Normalized Energy (kWh)	(C) Current Base Revenue	(D) Proposed Rate ¢/kWh	(E) Proposed Revenue Increase	(F) Proposed Base Revenue	(G) Increase
	Uniform Tariff Rates:						99,250,892		
1	Residential Service	1	412,772	4,905,224,592	$ 411,592,160	0.7320	$ 35,906,244	447,498,404	8.72%
2	Master Metered Mobile Home Park	3	23	4,983,593	394,984	0.7320	$ 36,480	431,464	9.24%
3	Residential Service Time-of-Day	5	1,483	26,868,737	2,143,865	0.7320	$ 196,679	2,340,544	9.17%
4	Small General Service	7	28,078	143,241,424	15,298,850	0.7320	$ 1,048,527	16,347,377	6.85%
5	Large General Service - Secondary	9S	33,046	3,164,200,200	192,062,186	0.7320	$ 23,161,946	215,224,132	12.06%
6	Large General Service - Primary	9P	203	462,178,285	23,972,684	0.7320	$ 3,383,145	27,355,829	14.11%
7	Large General Service - Transmission	9T	3	2,426,064	130,560	0.7320	$ 17,759	148,319	13.60%
8	Dusk to Dawn Lighting	15	0	6,399,685	1,227,944	0.7320	$ 46,846	1,274,790	3.81%
9	Large Power Service - Secondary	19S	1	6,349,085	326,761	0.7320	$ 46,475	373,236	14.22%
10	Large Power Service - Primary	19P	106	2,119,873,345	95,632,247	0.7320	$ 15,517,473	111,149,720	16.23%
11	Large Power Service - Transmission	19T	2	33,704,165	1,456,070	0.7320	$ 246,714	1,702,784	16.94%
12	Agricultural Irrigation Service	24	17,415	1,752,403,245	116,644,400	0.7320	$ 12,827,592	129,471,992	11.00%
13	Unmetered General Service	40	1,296	12,162,729	901,646	0.7320	$ 89,031	990,677	9.87%
14	Street Lighting	41	1,344	26,964,987	3,241,072	0.7320	$ 197,384	3,438,456	6.09%
15	Traffic Control Lighting	42	454	2,826,554	$142,204	0.7320	$ 20,690	162,894	14.55%
16	Total Uniform Tariffs		496,226	12,669,806,690	$ 865,167,633		92,742,985	957,910,618	10.72%
17	Special Contracts								
18	Micron	26	1	466,006,690	$ 18,089,440	0.7320	$ 3,411,169	21,500,609	18.86%
19	J R Simplot	29	1	186,125,488	6,829,907	0.7320	$ 1,362,439	8,192,346	19.95%
20	DOE	30	1	236,926,098	8,868,760	0.7320	$ 1,734,299	10,603,059	19.56%
21	Total Special Contracts		3	889,058,276	$ 33,788,107		$ 6,507,907	40,296,014	19.26%
22	Total Idaho Retail Sales		496,229	13,558,864,966	$ 898,955,740		$ 99,250,892	998,206,632	11.04%

Note:
June 1, 2014 - May 31, 2015, Forecast

Attachment I
Case No. IPC-E-14-05
Staff Comments
05/16/14

Idaho Power Company Revenue Sharing
Calculation of Revenue Impact
Case No. IPC-E-14-05

Line No	Tariff Description	Rate Sch. No.	(A) Average Number of Customers	(B) Normalized Energy (kWh)	(C) Proposed NPSE Base Revenue	(D) Percentage of Idaho Base Revenues	(E) Allocated Revenue Sharing Benefit	(F) Cents per kWh Rate	(G) Percent Revenue Change
	Uniform Tariff Rates:						**$ (7,602,043)**		
1	Residential Service	1	412,772	4,905,224,592	$ 447,498,404	44.83%	$ (3,408,014)	(0.0695)	(0.76)%
2	Master Metered Mobile Home Park	3	23	4,983,593	431,464	0.04%	(3,286)	(0.0659)	(0.76)%
3	Residential Service Time-of-Day	5	1,483	26,868,737	2,340,544	0.23%	(17,825)	(0.0663)	(0.76)%
4	Small General Service	7	28,078	143,241,424	16,347,378	1.64%	(124,497)	(0.0869)	(0.76)%
5	Large General Service - Secondary	9S	33,046	3,164,200,200	215,224,132	21.56%	(1,639,083)	(0.0518)	(0.76)%
6	Large General Service - Primary	9P	203	462,178,285	27,355,829	2.74%	(208,334)	(0.0451)	(0.76)%
7	Large General Service - Transmission	9T	3	2,426,064	148,319	0.01%	(1,130)	(0.0466)	(0.76)%
8	Dusk to Dawn Lighting	15	0	6,399,685	1,274,790	0.13%	(9,708)	(0.1517)	(0.76)%
9	Large Power Service - Secondary	19S	1	6,349,085	373,236	0.04%	(2,842)	(0.0448)	(0.76)%
10	Large Power Service - Primary	19P	106	2,119,873,345	111,149,720	11.13%	(846,483)	(0.0399)	(0.76)%
11	Large Power Service - Transmission	19T	2	33,704,165	1,702,784	0.17%	(12,968)	(0.0385)	(0.76)%
12	Agricultural Irrigation Service	24	17,415	1,752,403,245	129,471,992	12.97%	(986,020)	(0.0563)	(0.76)%
13	Unmetered General Service	40	1,296	12,162,729	990,677	0.10%	(7,545)	(0.0620)	(0.76)%
14	Street Lighting	41	1,344	26,964,987	3,438,456	0.34%	(26,186)	(0.0971)	(0.76)%
15	Traffic Control Lighting	42	454	2,826,554	$162,894	0.02%	-$1,241	(0.0439)	(0.76)%
16	Total Uniform Tariffs		496,226	12,669,806,690	$ 957,910,618	95.96%	$ (7,295,161)		(0.76)%
17	Special Contracts								
18	Micron	26	1	466,006,690	$ 21,500,609	2.15%	$ (163,742)	NA	(0.76)%
19	J R Simplot	29	1	186,125,488	8,192,346	0.82%	(62,390)	NA	(0.76)%
20	DOE	30	1	236,926,098	10,603,060	1.06%	(80,750)	NA	(0.76)%
21	Total Special Contracts		3	889,058,276	$ 40,296,014	4.04%	$ (306,882)		(0.76)%
22	Total Idaho Retail Sales		496,229	13,558,864,966	$ 998,206,633	100.00%	$ (7,602,043)		(0.76)%

Note:
June 1, 2014 - May 31, 2015, Forecast

Idaho Power Company DSM Rider Transfer
Calculation of Revenue Impact
Case No. IPC-E-14-05

							One-Time DSM Rider Benefit			On-Going DSM Rider Benefit			
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No	Tariff Description	Rate Sch. No.	Average Number of Customers	Normalized Energy (kWh)	Proposed NPSE Base Revenue	Percentage of Idaho Base Revenues	Allocated One-Time DSM Rider Benefit	Cents per kWh Rate	Percent Revenue Change	Allocated On-Going DSM Rider Benefit	Cents per kWh Rate	Percent Revenue Change	Total DSM Rider Benefit ¢/kWh
	Uniform Tariff Rates:						$ (16,029,724)			$ (3,970,276)			
1	Residential Service	1	412,772	4,905,224,592	$ 447,498,404	44.83%	$ (7,186,163)	(0.1465)	(1.61)%	$ (1,436,337)	$ (0.0293)	-0.32%	(0.1758)
2	Master Metered Mobile Home Park	3	23	4,983,593	431,464	0.04%	(6,929)	(0.1390)	(1.61)%	$ (1,459)	$ (0.0293)	-0.34%	(0.1683)
3	Residential Service Time-of-Day	5	1,483	26,868,737	2,340,544	0.23%	(37,586)	(0.1399)	(1.61)%	$ (7,868)	$ (0.0293)	-0.34%	(0.1692)
4	Small General Service	7	28,078	143,241,424	16,347,378	1.64%	(262,515)	(0.1833)	(1.61)%	$ (41,944)	$ (0.0293)	-0.26%	(0.2125)
5	Large General Service - Secondary	9S	33,046	3,164,200,200	215,224,132	21.56%	(3,456,182)	(0.1092)	(1.61)%	$ (926,534)	$ (0.0293)	-0.43%	(0.1385)
6	Large General Service - Primary	9P	203	462,178,285	27,355,829	2.74%	(439,294)	(0.0950)	(1.61)%	$ (135,334)	$ (0.0293)	-0.49%	(0.1243)
7	Large General Service - Transmission	9T	3	2,426,064	148,319	0.01%	(2,382)	(0.0982)	(1.61)%	$ (710)	$ (0.0293)	-0.48%	(0.1275)
8	Dusk to Dawn Lighting	15	0	6,399,685	1,274,790	0.13%	(20,471)	(0.3199)	(1.61)%	$ (1,874)	$ (0.0293)	-0.15%	(0.3492)
9	Large Power Service - Secondary	19S	1	6,349,085	373,236	0.04%	(5,994)	(0.0944)	(1.61)%	$ (1,859)	$ (0.0293)	-0.50%	(0.1237)
10	Large Power Service - Primary	19P	106	2,119,873,345	111,149,720	11.13%	(1,784,900)	(0.0842)	(1.61)%	$ (620,736)	$ (0.0293)	-0.56%	(0.1135)
11	Large Power Service - Transmission	19T	2	33,704,165	1,702,784	0.17%	(27,344)	(0.0811)	(1.61)%	$ (9,869)	$ (0.0293)	-0.58%	(0.1104)
12	Agricultural Irrigation Service	24	17,415	1,752,403,245	129,471,992	12.97%	(2,079,129)	(0.1186)	(1.61)%	$ (513,135)	$ (0.0293)	-0.40%	(0.1479)
13	Unmetered General Service	40	1,296	12,162,729	990,677	0.10%	(15,909)	(0.1308)	(1.61)%	$ (3,561)	$ (0.0293)	-0.36%	(0.1601)
14	Street Lighting	41	1,344	26,964,987	3,438,456	0.34%	(55,217)	(0.2048)	(1.61)%	$ (7,896)	$ (0.0293)	-0.23%	(0.2341)
15	Traffic Control Lighting	42	454	2,826,554	$162,894	0.02%	-$2,616	(0.0925)	(1.61)%	$ (828)	$ (0.0293)	-0.51%	(0.1218)
16	Total Uniform Tariffs		496,226	12,669,806,690	$ 957,910,618	95.96%	$ (15,382,630)		(1.61)%	$ (3,709,944)		-0.39%	
17	Special Contracts												
18	Micron	26	1	466,006,690	$ 21,500,609	2.15%	$ (345,268)	(0.0741)	(1.61)%	$ (136,455)	$ (0.0293)	-0.63%	(0.1034)
19	J R Simplot	29	1	186,125,488	8,192,346	0.82%	(131,557)	(0.0707)	(1.61)%	$ (54,501)	$ (0.0293)	-0.67%	(0.1000)
20	DOE	30	1	236,926,098	10,603,060	1.06%	(170,269)	(0.0719)	(1.61)%	$ (69,376)	$ (0.0293)	-0.65%	(0.1011)
21	Total Special Contracts		3	889,058,276	$ 40,296,014	4.04%	$ (647,094)		(1.61)%	$ (260,332)		-0.65%	
22	Total Idaho Retail Sales		496,229	13,558,864,966	$ 998,206,633	100.00%	$ (16,029,724)		(1.61)%	$ (3,970,276)		-0.40%	

Note:
June 1, 2014 - May 31, 2015, Forecast

Idaho Power Company - Schedule 55 Rates
Case No. IPC-E-14-05

Line No	Tariff Description	Rate Sch. No.	(A) Average Number of Customers	(B) Normalized Energy (kWh)	(C) Proposed NPSE Base Revenue	(D) Traditional PCA ¢/kWh	(E) Revenue Sharing ¢/kWh	(F) On-Going DSM Rider ¢/kWh	(G) One-Time DSM Rider ¢/kWh	(H) Schedule 55 Rates ¢/kWh
	Uniform Tariff Rates:									
1	Residential Service	1	412,772	4,905,224,592	$ 447,498,404	0.7305	$ (0.0695)	(0.0293)	(0.1465)	**0.4852**
2	Master Metered Mobile Home Park	3	23	4,983,593	431,464	0.7305	$ (0.0659)	(0.0293)	(0.1390)	**0.4963**
3	Residential Service Time-of-Day	5	1,483	26,868,737	2,340,544	0.7305	$ (0.0663)	(0.0293)	(0.1399)	**0.4950**
4	Small General Service	7	28,078	143,241,424	16,347,378	0.7305	$ (0.0869)	(0.0293)	(0.1833)	**0.4310**
5	Large General Service - Secondary	9S	33,046	3,164,200,200	215,224,132	0.7305	$ (0.0518)	(0.0293)	(0.1092)	**0.5402**
6	Large General Service - Primary	9P	203	462,178,285	27,355,829	0.7305	$ (0.0451)	(0.0293)	(0.0950)	**0.5611**
7	Large General Service - Transmission	9T	3	2,426,064	148,319	0.7305	$ (0.0466)	(0.0293)	(0.0982)	**0.5565**
8	Dusk to Dawn Lighting	15	0	6,399,685	1,274,790	0.7305	$ (0.1517)	(0.0293)	(0.3199)	**0.2296**
9	Large Power Service - Secondary	19S	1	6,349,085	373,236	0.7305	$ (0.0448)	(0.0293)	(0.0944)	**0.5620**
10	Large Power Service - Primary	19P	106	2,119,873,345	111,149,720	0.7305	$ (0.0399)	(0.0293)	(0.0842)	**0.5771**
11	Large Power Service - Transmission	19T	2	33,704,165	1,702,784	0.7305	$ (0.0385)	(0.0293)	(0.0811)	**0.5816**
12	Agricultural Irrigation Service	24	17,415	1,752,403,245	129,471,992	0.7305	$ (0.0563)	(0.0293)	(0.1186)	**0.5263**
13	Unmetered General Service	40	1,296	12,162,729	990,677	0.7305	$ (0.0620)	(0.0293)	(0.1308)	**0.5084**
14	Street Lighting	41	1,344	26,964,987	3,438,456	0.7305	$ (0.0971)	(0.0293)	(0.2048)	**0.3993**
15	Traffic Control Lighting	42	454	2,826,554	$162,894	0.7305	$ (0.0439)	(0.0293)	(0.0925)	**0.5648**
16	Total Uniform Tariffs		496,226	12,669,806,690	$ 957,910,618					
17	Special Contracts									
18	Micron	26	1	466,006,690	$ 21,500,609	0.7305	NA	(0.0293)	(0.1034)	0.5978
19	J R Simplot	29	1	186,125,488	8,192,346	0.7305	NA	(0.0293)	(0.1000)	0.6012
20	DOE	30	1	236,926,098	10,603,060	0.7305	NA	(0.0293)	(0.1011)	0.6001
21	Total Special Contracts		3	889,058,276	$ 40,296,014					
22	Total Idaho Retail Sales		496,229	13,558,864,966	$ 998,206,633					

Note:
June 1, 2014 - May 31, 2015, Forecast

Attachment L
Case No. IPC-E-14-05
Staff Comments
05/16/14

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 16TH DAY OF MAY 2014, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-14-05, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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